Quantifying CO_2 abatement costs in the power sector

Kenneth Van den Bergh, Erik Delarue*

University of Leuven (KU Leuven) – Energy Institute

Celestijnenlaan 300 box 2421, B-3001 Leuven, Belgium

*Corresponding author: +32 163 322 521, erik.delarue@mech.kuleuven.be

Abstract

CO_2 cap-and-trade mechanisms and CO_2 emission taxes are becoming increasingly widespread. To assess the impact of a CO_2 price, marginal abatement cost curves (MACCs) are a commonly used tool by policy makers, providing a direct graphical link between a CO_2 price and the expected abatement. However, such MACCs can suffer from issues related to robustness and granularity. This paper focuses on the relation between a CO_2 emission cost and CO_2 emission reductions in the power sector. The authors present a new methodology that improves the understanding of the relation between a CO_2 cost and CO_2 abatement. The methodology is based on the insight that CO_2 emissions in the power sector are driven by the composition of the conventional power portfolio, the residual load and the generation costs of the conventional units. The methodology addresses both the robustness issue and the granularity issue related to MACCs. The methodology is based on a bottom-up approach, starting from engineering knowledge of the power sector. It offers policy makers a new tool to assess CO_2 abatement options. The methodology is applied to the Central Western European power system and illustrates possible interaction effects between, e.g., fuel switching and renewables deployment.

Keywords

CO_2 emission policy, marginal abatement cost curves, power sector.

1. Introduction

Policy measures aiming at reducing CO_2 emissions are becoming increasingly widespread. In this respect the power sector plays an important role due to its notable share in total emissions - about 30% of European CO_2 emissions originate from the power sector (Eurostat, 2014) - and its considerable abatement potential (Rootzén and Johnsson, 2013).

Two main types of (direct) emission policies exist; a price instrument imposing a fixed payment per emitted unit (e.g., a CO_2 emission tax) and a quantity instrument imposing an aggregated emission cap, possibly combined with a trade mechanism in emission allowances (e.g., a cap-and-trade mechanism). Both types of policy result in a cost of emitting CO_2. A widely used tool to think about the impact of emission policy is the concept of marginal abatement cost curves (MACCs). A MACC plots the shadow price corresponding to an emission constraint of increasing severity against the quantity abated. A point on the MACC represents the marginal cost of abating an additional unit of emissions (Ellerman and Decaux, 1998). As such, a MACC links emission abatement to an emission cost (being a CO_2 tax or a CO_2 price)[1].

Roughly speaking, two main methods are used to develop MACCs. The first method consists of a top-down approach based on macroeconomic models, often in a general equilibrium framework. The second method uses a bottom-up approach, based on detailed optimization models or expert knowledge of a system, mostly in a partial equilibrium framework (Jacoby, 1998). The advantage of the top-down approach is that it aims to capture all effects of a CO_2 cost, including feedback loops like changes in fossil fuel prices. However, these top-down models are limited to less detailed representations of each sector and each country. The engineering bottom-up approach allows a very detailed description of a certain sector, but this comes at the expense that not all effects and feedback loops in the system can be captured (Jacoby, 1998). The trade-off between bottom-up and top-down models is a reoccurring discussion in

[1] Throughout this paper the term *CO_2 cost* is used, expressed in EUR/tCO_2. A CO_2 cost might reflect a CO_2 price within a cap-and-trade mechanism (e.g., the European Emission Trading System) or a CO_2 tax.

energy systems modeling and often aspects from both approaches are combined (Labandeira et al., 2009). Models often referred to in the literature on MACCs are, among others, the EPPA model of MIT (Paltsev et al., 2005), the POLES model developed by IEPE (European Commission, 2010; Criqui et al., 1999) and the DART model developed at the Kiel Institute for World Economics (Klepper et al., 2003).

Although MACCs are a commonly used tool to analyze the impact of a CO_2 cost on CO_2 abatement – or vice versa, some general issues can be raised with regard to these curves. For the construction of MACCs, models are used often based on a centralized optimization, with perfect information. In reality, specific technical constraints, and elements of imperfect information and risk perception result in abatement measures getting implemented over a range of CO_2 prices, rather than on distinct CO_2 prices. MACCs are also rather static snap-shots (Vogt-Schilb and Hallegatte, 2014). As CO_2 prices rise, measures will get implemented and learning effects will be triggered. In this regard, as different abatement measures relate to different time horizons (e.g., pure operational measures versus long term investments) it might not be straightforward putting them on a single axis. When derived from modeling (either top-down or bottom-up), some further reflections are to be made regarding MACCs. Kesicki and Ekins (2012) give an overview of the shortcomings of MACCs, with robustness being one of the most critical ones. Each model used to derive MACCs is based on external parameters (Kesicki, 2013). A MACC is robust if it is insensitive to changes in these parameters. In the literature, consensus seems to be that MACCs are not very robust (Klepper and Peterson, 2006; Fischer and Morgenstern, 2006; Delarue et al., 2010; Morris et al., 2012). Another issue with regard to MACCs is the level of granularity. A MACC with high granularity might give a detailed cost-emission relation of a single abatement technology, without taking account of overlapping and mutually influencing abatement technologies. On the other hand, a MACC with low granularity might give an aggregated cost-emission relation but without revealing the driving technology of the abatement at a certain CO_2 emission cost.

This paper addresses both the robustness issue and the granularity issue related to marginal abatement cost curves, applied to the power sector. A new methodology is developed, based on knowledge of the drivers of CO_2 emissions in the power sector. A key concept of the presented methodology is the so-called absolute emission plane, which represents the relation between CO_2 emissions in the power sector and its drivers. MACCs can be derived from the absolute emission plane by combining it with the relation between a CO_2 emissions cost and the respective emission drivers. The methodology provides insight in the way that a MACC is composed combining several abatement technologies (i.e., the granularity issue). The methodology further illustrates how changes in external parameters influence the MACC (i.e., the robustness issue). The main objective of the presented methodology is to deepen the understanding of the relation between a CO_2 emission cost and CO_2 emission abatement in the power sector. The methodology can be used by policy makers to quantify the impact of a CO_2 emission cost and assess the robustness of this impact.

The presented methodology is based on a bottom-up approach. To this end, a partial equilibrium model of the power sector is used, describing the power sector with a high level of detail. The methodology is illustrated with a case study of the Central Western European (CWE) power sector (Germany, France, Belgium, The Netherlands, and Luxembourg).

This paper proceeds as follows. Section 2 describes a framework to think about CO_2 emissions and CO_2 abatement in the power sector and the new methodology to derive MACCs. Section 3 presents the results of this methodology for a case study of the Central Western European power sector, addressing the policy implications. Section 4 discusses these results and section 5 concludes.

2. Methods

The applied methodology falls apart in two steps. First, a framework is presented to structure the drivers of CO_2 emissions in the power sector. Second, this framework can be used as a basis to study MACCs, considering the robustness issue and granularity issue related to MACCs. This section also discusses the investigated case study and the model.

2.1. CO_2 emissions in the power sector: a framework

Different parameters that influence the CO_2 emissions from the power sector can be identified and classified in 3 main categories of CO_2 emission drivers in the power sector:

(1) the composition of the conventional power plant portfolio;

(2) the residual load to be met by the conventional power plant portfolio;

(3) the marginal generation costs of the conventional power plant portfolio.

Each of these drivers is discussed more in detail in this section.

2.1.1. The conventional generation portfolio

The conventional generation portfolio consists of power plants that can be actively controlled by generation companies. The most common conventional units are nuclear power plants and fossil fuel fired power plants (coal, gas, lignite, and fuel oil). Renewables generation (wind and sun) can only be actively controlled to a limited extent and are therefore not considered as part of the conventional portfolio (but accounted for in the residual load).

The composition of the conventional generation portfolio is a first important driver of the CO_2 emissions in the power sector. Depending on the fuel mix and the average power plant age (impacting, among others, the operating efficiency), portfolios can have very different CO_2 intensities. To illustrate this, Figure 1 shows the CO_2 intensity of electricity generation for some European Member States. The French generation portfolio consists mainly of nuclear power plants and hydro power plants, resulting in a very low CO_2 intensity. Electricity generation in Poland, on the other hand, is to a large extent based on coal and lignite fired plants, resulting in a high CO_2 intensity. The other shown member states have CO_2 intensities between these two relative extreme values.

CO_2 abatement can be achieved by changing the installed conventional generation capacity or its technical parameters. Possible abatement actions are (non-exhaustive list):

- investments in nuclear power plants (CO_2 free electricity generation);
- investments in new gas fired plants (relatively low CO_2 emissions);
- closing down lignite or coal fired plants (relatively high CO_2 emissions);
- retrofitting existing fossil fuel fired plants (resulting in a higher efficiencies);
- implementing carbon capture and storage.

A CO_2 cost might trigger CO_2 abatement by changing the conventional power plant portfolio through one of the listed abatement options. Conventional power plant portfolios are relatively inert, implying that a CO_2 cost causes CO_2 abatement by changing the composition of the conventional portfolio only in the long term. For example, typical lead times for new conventional plants range from 2 years for combined cycle units up to 7 years for nuclear units (IEA, 2010).

2.1.2. The residual load

The residual load that has to be met by the conventional power plant portfolio is the original electricity demand minus generation from renewables and cogeneration units. Logically, the higher the residual load, the higher the CO_2 emissions from the power system.

CO_2 abatement can be achieved by reducing the residual load. Possible abatement actions are (non-exhaustive list):

- investments in renewable generation capacity (wind and sun);
- increasing the energy efficiency of electrical appliances;
- demand reduction.

A CO_2 cost might trigger CO_2 abatement by decreasing the residual load through one of the listed abatement options. Decreasing the residual load plays a role in the medium term. For example, lead times of new wind and solar capacity are about 1 year (IEA, 2010). In the short term (days to weeks), electricity demand is rather inelastic. In the medium term, however, the electricity demand can be expected to be partially elastic, representing, among others, investments in more efficient appliances.

2.1.3. The marginal generation costs

The marginal generation costs of the available conventional plants determine the merit order. The merit order is a ranking of all available power plants in ascending order of marginal generation cost. The intersection of the merit order with the residual electricity load divides the power plant portfolio in operating power units, i.e., the ones at the left of the intersection, and non-operating power plants, i.e., the ones at the right of the intersection[2] (see Figure 2). Power plants with low marginal generation costs are thus more likely to be online than power plants with higher marginal generation costs. At 2014 fuel and CO_2 prices in Europe, the ranking in the merit order is roughly speaking the following: nuclear units, lignite fired units, coal fired units, gas fired units and fuel oil fired units. At the time of writing, coal fired plants are hence more likely to produce in Europe than gas fired power plants.

CO_2 abatement can be achieved by changing the marginal generation costs of conventional power plants, resulting in so-called fuel switching. Fuel switching occurs when the marginal generation cost of high-emitting plants (e.g., coal fired plants) becomes higher than the marginal generation cost of low-emitting plants (e.g., gas fired plants), leading to a switch of these plants in the merit order. The result is that more generation is coming from low-emitting plants and overall CO_2 emissions decrease.

A CO_2 cost might trigger fuel switching by increasing the marginal generation costs of emitting units. Fuel switching is a pure operational abatement technology, responding rapidly to a CO_2 cost (power plant operators schedule their plants on an hourly to daily basis).

2.1.4. Summary

This section discusses the three main drivers of CO_2 emissions in the power sector. All possible abatement options can be assigned to one of these drivers. Each driver is linked to a certain time frame. Table I summarizes this section. An abatement option can be triggered by a CO_2 cost, but also by other energy and climate policies (e.g., renewables support schemes can trigger investments in renewables) or by macroeconomic evolutions (e.g., changing fuel prices might trigger fuel switching) (Van den Bergh et al., 2013). The focus in this paper is on a CO_2 cost triggering CO_2 abatement.

2.2. Analysis plan to study MACCs

Based on the insights in the CO_2 emissions drivers, a detailed marginal abatement cost curve of the power sector can be composed in three steps:

[2] This is only true by approximation. Dynamic power plant constraints might cause power plants with higher marginal generation costs to be online while plants with lower marginal costs are offline.

1) Quantify the relation between a CO_2 cost and each of the 3 drivers of CO_2 emissions in the power sector (conventional portfolio, residual load and marginal generation costs). This relation can be based on a modeling exercise or expert knowledge.
2) Quantify the relation between the aggregated CO_2 emissions in the power sector and its 3 drivers. The aggregated CO_2 emissions follow from the partial equilibrium model of the power sector with varying conventional portfolio, varying residual load and varying marginal generation costs as input. The result of this step is a 4-dimensional surface (three CO_2 drivers plus the aggregated CO_2 emissions), referred to as the absolute emission plane. Each point on this 4-dimensional surface represents an operational state of the power sector. The absolute emission plane is needed to capture the interaction between different CO_2 abatement options.
3) Merge the information of the two previous steps to find the relation between a CO_2 cost and CO_2 emissions in the power sector. This relation leads to the marginal abatement cost curve of the power sector.

The different effects of a CO_2 cost on each CO_2 driver may not just be summed up, as the relation between a CO_2 emission driver and the aggregated CO_2 emissions depends on the other CO_2 emission drivers as well. For instance, a change in marginal generation costs – caused by a CO_2 cost – has a different effect on the CO_2 emissions, depending on the change in residual load – caused by the same CO_2 cost. This indicates interaction between the different CO_2 emission drivers, which is captured by the partial equilibrium model and represented by the absolute emission plane.

If a parameter which is external to the analysis changes (e.g., fossil fuel prices or capital costs of renewables), the first and the third step of the analysis plan have to be repeated. This illustrates the robustness issue. Changes in external parameters affect the MACC.

In the third step of the analysis plan, several abatement technologies are combined into one single CO_2 cost-emission relation. The bottom-up nature of this methodology allows decomposing the total CO_2 abatement in its driving abatement technologies. This relates to the granularity issue.

The methodology, which is described in rather abstract terms up until now, will be illustrated in section 3 for a real-life case study. The MACC of the Central Western European power sector will be discussed, considering two abatement technologies triggered by a CO_2 cost: fuel switching and investments in wind energy. Fuel switching is a significant abatement option in the power sector. Wind energy can be an important source of CO_2 free electricity generation, with a levelized cost of electricity (LCOE) which is several times lower than the LCOE of photovoltaic energy (IEA, 2010). The case study considers a medium term time frame. Within this time frame, both fuel switching and investments in wind energy might take place. The composition of the conventional power plant portfolio, which can change only in the long term, is assumed to be fixed.

The presented methodology implicitly assumes that the three CO_2 emission drivers are only linked through a CO_2 cost. The interdependencies between marginal generation costs (fossil fuel prices), conventional power plant portfolios (fossil fuel fired capacities) and residual load (electricity demand and renewable investments), caused by factors other than a CO_2 cost, are not captured by the methodology. This originates from the bottom-up nature of the presented methodology.

2.3. System description

The methodology is applied to the Central Western European (CWE) power sector, based on 2012 data. The CWE region covers France, Germany, Belgium, The Netherlands and Luxembourg (see Figure 3). Each country is represented by one node and the market coupling is established according to the Net Transfer Capacity (NTC) method. The conventional generation portfolio in this region consists of 342 units with a total generation capacity of 175 GW. The composition of the conventional portfolio is considered to be fixed in the remainder of the study (only the impact on CO_2 emissions of the residual load and marginal generation costs are investigated). Table II gives an overview of the installed capacity together with the parameters assigned to the respective units. Different rated efficiencies are allocated to power plants depending on the year of commissioning. The average 2012 fuel prices were used (EEX, 2013).

A whole year is considered in order to take the seasonality of the electricity demand and renewables generation into account. The 2012 annual demand in the CWE region was 1220 TWh (demand corrected for neglected import and export with countries not included in the model). 16% of this demand was fulfilled by renewable generation (wind, photovoltaic, bio, and hydro) and 13% by electricity from cogeneration units. The remaining residual load, to be fulfilled by the conventional portfolio, was 866 TWh. Historical hourly demand time series and renewable generation time series are used.

Demand data, renewables data, NTC values and power plant portfolio data originates from Entso-e (2014), Elia (2014), Tennet (2014) and the Umweltbundesamt (2014).

2.4. Model description

A detailed unit commitment model of the power sector is developed to simulate the CWE power system. A unit commitment model is a partial equilibrium model that determines the optimal scheduling of a given set of power plants to meet the electricity demand, taking account of operational constraints. The presented unit commitment model is purely operational (i.e., no investments in generation or transmission capacity are considered), deterministic (i.e., neglecting uncertainties in the power system) and assumes an inelastic electricity demand.

The unit commitment problem is formulated as a mixed-integer linear program (MILP) in GAMS 24.2 and solved by CPLEX 12.6 with a relative optimality gap of 1%. Hereunder, the basic equations of the unit commitment model are listed, based on Carrión and Arroyo (2006) and Arroyo and Conejo (2000). A more extended version of the model description, including tighter and compacter formulations of the constraints, can be found in Van den Bergh et al. (2014). Table III gives the nomenclature used in the model description.

The objective function of the unit commitment model is minimization of the total operational system cost, consisting of generation costs and start-up costs.

$$\min \sum_i \sum_t \left(z_{i,t}\ CO_i + p_{i,t}\ MC_i \right) + SUC_i\ v_{i,t} \Big) \qquad (1)$$

The objective function is subject to the market clearing condition (equation 2), renewables curtailment limits (equation 3), power plant generation limits (equation 4), minimum down and up times (equations 5-6), the logic binary relation (equation 7) and trade capacity limits (equations 8-9).

$$\sum_i AP_{n,i} \left(z_{i,t}\ P_i^{min} + p_{i,t}\right) + T_{n,t}^{CHP} + T_{n,t}^{RES} - u_{n,t}^{RES} = D_{n,t} + i_{n,t} \quad \forall\, n,t \tag{2}$$

$$0 \le u_{n,t}^{RES} \le T_{n,t}^{RES} \quad \forall\, n,t \tag{3}$$

$$0 \le p_{i,t} \le \left(P_i^{max} - P_i^{min}\right) z_{i,t} \quad \forall\, i,t \tag{4}$$

$$1 - z_{i,t} \ge \sum_{t'=t+1-MDT_i}^{t} w_{i,t'} \quad \forall\, i,t \tag{5}$$

$$z_{i,t} \ge \sum_{t'=t+1-MUT_i}^{t} v_{i,t'} \quad \forall\, i,t \tag{6}$$

$$z_{i,t-1} - z_{i,t} + v_{i,t} - w_{i,t} = 0 \quad \forall\, i,t \tag{7}$$

$$i_{n,t} = \sum_l A_{l,n}\, f_{l,t} \quad \forall\, n,t \tag{8}$$

$$-F_l^{max} \le f_{l,t} \le F_l^{max} \quad \forall\, n,t \tag{9}$$

The model solves a whole year with an hourly time resolution in weekly blocks. Different weekly optimizations overlap with one day and are coupled by means of sequential boundary conditions, in order to ensure a feasible and optimal coupling between the different optimizations. The model is calibrated so that the simulated generation in a simulation with historical input data matches the historical observed generation in the 2012 CWE power system. It takes about 3 hours to solve the unit commitment model for one year for the CWE region on an Intel® Core™ i7-2620M CPU @ 2.7 GHz with 8 GB RAM.

3. Results

The analysis plan discussed in section 2.2 is illustrated in this section based on a case study of the CWE power sector. Sections 3.1 and 3.2 show the relation between a CO_2 cost and two CO_2 drivers (the marginal generation costs and the residual load). Only two different abatement options are investigated in detail in this study (i.e., fuel switching and wind energy), but the methodology can be easily extended to other abatement options. Section 3.3 relates the CO_2 emission drivers with the aggregated CO_2 emissions from the power sector and section 3.4 expresses the relationship between a CO_2 cost and the CO_2 emissions.

3.1. CO_2 cost versus marginal generation costs: fuel switching

The relation between a CO_2 cost and a marginal generation cost is different for each power plant, depending on the generation type and its efficiency. The marginal generation cost *MC* of a power plant is the derivative of the total generation cost function *TC(P)* with respect to the power output *P*.

$$\mathrm{TC(P)} = \frac{\mathrm{FC+EF \cdot CC}}{\eta} \cdot \mathrm{P} \quad (10)$$

$$\mathrm{MC} = \frac{\mathrm{FC+EF \cdot CC}}{\eta} \quad (11)$$

with *FC* the fuel cost in [EUR/MWh_{fuel}], *EF* the emission factor in [tCO_2/MWh_{fuel}], *CC* the CO_2 cost in [EUR/tCO_2] and η the rated efficiency. The operating efficiency of the power plant is function of the power output of the unit (the operating efficiency decreases in part load operation). However, for the sake of simplicity, the dependence of the efficiency on the power output is neglected in this section[3]. Note that the marginal generation cost (see equation 11) is used in the objective function of the partial equilibrium model of the power sector (see equation 1).

Equation 11 gives the relation between a CO_2 cost and the marginal generation cost of one power plant. However, a metric is required containing information about all generation costs in the power portfolio. The proposed metric is the difference between the average marginal generation cost of a coal fired power plant and the average marginal generation cost of a gas fired power plant. The rationale is that coal fired and gas fired units are the main source of fuel switching as they are operating close to the margin (i.e., close to the intersection of the merit order with the demand curve). The metric contains average marginal generation costs, averaged in time and averaged over different units (with different efficiencies).

Figure 4 shows the relation between a CO_2 cost and the difference in average marginal generation costs between coal fired and gas fired plants. Figure 4 is based on 2012 average fuel price data (12 EUR/MWh

[3] The dependence of the efficiency on the power output is taken into account in the unit commitment model. The non-linear production cost curve is approximated by a linear approximation (see equation 1).

for coal and 25 EUR/MWh for gas[4], EEX, 2013) and average power plant characteristics. To investigate the impact of changes in external parameters, the relation between a CO_2 cost and marginal generation costs is also considered for a case with a 10% higher coal price and the 2012 gas price, and for a case with a 10% higher gas price and the 2012 coal price. Figure 4 indicates that coal fired power plants become more expensive than gas fired power plants, in terms of marginal generation costs and at 2012 fuel prices, as of a CO_2 cost of 40 EUR/tCO_2.

3.2. CO_2 cost versus residual demand: wind energy investments

A CO_2 cost might promote investments in wind generation capacity, resulting in a lower residual demand to be fulfilled by the conventional power plant portfolio. In this study, a dedicated model is used and set up to determine the relation between a CO_2 cost and wind energy investments (i.e., a different model than the unit commitment model discussed in section 2.4). The model gives the amount of installed wind capacity, assuming the conventional portfolio to be fixed and solely based on 2012 power system data (fuel prices, demand data, etc.). The investments in wind energy are solely triggered by a CO_2 emission cost, as no subsidies for wind energy are considered in the investment model.

The model considers one period with the annually average residual demand and a merit order of the conventional generation portfolio (based on annually average fuel prices). The model estimates the wholesale electricity price as the marginal generation cost of the last generating unit in the merit order needed to meet the average residual demand. If the electricity price is higher than the levelized cost of electricity (LCOE) of wind, an extra MW of wind energy is installed resulting in a decrease in the average residual demand with 0.2 MW for onshore wind (20% capacity factor) and 0.3 MW for offshore wind (30% capacity factor). Then the new electricity price is calculated as the marginal generation cost of the last generation unit in the merit order needed to meet the reduced average residual demand. This electricity price will be lower than the previous calculated price. This iterative process continues until the estimated electricity price equals the LCOE of wind or the wind capacity potential is reached (Kagiannas

[4] A coal price of 12 EUR/MWh corresponds to a price of 120 $/ton and a gas price of 25 EUR/MWh corresponds to a price of 10 $/MMBtu (2012 dollar-euro exchange rate).

et al., 2004). The simulations are repeated for different CO_2 emission costs. The model gives a rough estimation of the investments in wind triggered by a CO_2 cost. The amount of installed wind is translated into a decrease in residual demand by subtracting the wind generation (estimated based on a 20% capacity factor for onshore wind and 30% capacity factor for offshore wind) from the original residual demand. Table IV shows the data used in this investment model.

Figure 5 shows the residual demand including the additional wind generation as a function of the CO_2 cost. Again, the relation between a CO_2 cost and the residual demand is considered for a case with a 10% higher coal price and the 2012 gas price, and for a case with a 10% higher gas price and the 2012 coal price. This change in fuel prices impacts the decision of the wind investors as it changes the electricity price, but only to a limited extent. At higher fuel prices, wind investments start taking place at slightly lower CO_2 emission costs. The technical potential limit is not reached within the considered CO_2 cost range.

3.3. Absolute emission plane

The absolute emission plane of the power sector is, in its complete form, a 4-dimensional surface, containing the relation between the three CO_2 emission drivers and the CO_2 emissions in the power sector. Each point on the absolute emission plane represents a possible operational state of the power sector, given a certain power plant portfolio composition, certain marginal generation costs and a residual load. Each point on the absolute emission plane follows from a detailed simulation for a whole year (8760 hours) with the unit commitment model as described in section 2.3.

In this paper, the composition of the conventional portfolio is assumed fixed. As such, the absolute emission plane reduces to a 3-dimensional surface. Figure 6 shows the absolute emission plane of the 2012 CWE power sector. The figure indicates that absolute CO_2 emissions decrease with decreasing residual load and with increasing difference in marginal generation costs between coal fired and gas fired plants.

Note that the absolute emission plane of Figure 6 is based on specific 2012 data (e.g., 2012 time series for demand and renewables generation). Other time series would result in a slightly different absolute emission plane, however, the main trends and order of magnitudes would remain.

3.4. Deriving a marginal abatement cost curve

A marginal abatement cost curve of the power sector can be derived, based on the relation between a CO_2 cost and the CO_2 emission drivers on one hand (see section 3.1 and 3.2), and the relation between the CO_2 emission drivers and aggregated CO_2 emissions on the other hand (see section 3.3). The following steps need to be taken:

1. Indicate the appropriate reference point on the absolute emission plane (see point R at Figure 7a). The reference point gives the CO_2 emissions in the power sector in case of a zero CO_2 emission cost, and is indicated by the residual load and marginal cost difference that would occur in absence of a CO_2 emission cost. The reference point R at Figure 7a corresponds to the residual load and marginal cost difference in the CWE 2012 power system at zero CO_2 cost.
2. Project the relation between a CO_2 cost and each of the relevant CO_2 emission drivers on the absolute emission plane (see dashed lines at Figure 7a). Each dashed line corresponds to a CO_2 emission driver for a CO_2 cost ranging from 0 to 100 EUR/tCO_2, assuming the other CO_2 emission drivers fixed. The curve representing the relation between a CO_2 cost and marginal generation costs starts in the reference point and is parallel to the marginal cost axis (i.e., perpendicular to the residual load axis). This curve is the projection of Figure 4 on the absolute emission plane. The curve representing the relation between a CO_2 cost and residual load starts also in the reference point but is parallel to the residual load axis (i.e., perpendicular to the marginal cost axis). This curve is the projection of Figure 5 on the absolute emission plane.
3. Compose the different CO_2 cost-CO_2 driver relations into one relation between a CO_2 cost and CO_2 emissions. This latter relation is represented by a trajectory on the emission plane (see solid line at Figure 7a). The solid line is a collection of points on the absolute emission plane corresponding to the CO_2 emission drivers for a CO_2 cost ranging from 0 to 100 EUR/tCO_2. For

CO_2 prices up to 35 EUR/tCO_2, no investments in wind energy occur and the residual load remains unchanged. As a result, the first part of the solid line follows the dashed line corresponding to the relation CO_2 cost vs. marginal generation costs. At higher CO_2 prices, both dashed lines are influencing the trajectory of the solid line.

4. In a final step, the CO_2 cost-emission relation can be expressed relative to the CO_2 emissions in the reference point, which leads to the marginal abatement cost curve (see Figure 7b).

4. Discussion

The methodology presented in this paper gives insight in the impact of changing external parameters. Consider again a case with a 10% higher coal price and the 2012 gas price, and a case with a 10% higher gas price and the 2012 coal price. These changes in fossil fuel prices impact the relation between a CO_2 cost and each of the CO_2 emission drivers (see Figures 4 and 5). As a result, the MACC of the power sector will change as well. Figure 8 shows the marginal abatement cost curve and the corresponding trajectories on the absolute emission plane for different fossil fuel prices. This example relates to the robustness issue of MACCs and shows how the proposed methodology can bring insight in the mechanisms behind a changing external parameter – although the robustness issue is not very strong in this particular example. Note that a change in an external parameter changes both the reference point on the absolute emission plane, as well as the trajectory of the CO_2 cost-emission relation. Both aspects impact the shape of the marginal abatement cost curve.

The robustness of the CO_2 abatement caused by a CO_2 cost should be considered when designing CO_2 emission policies. As has been demonstrated, a CO_2 price affects emissions in the power sector via different ways. Careful assessment is required to capture the non-linear effects occurring in the power sector. On top, other policies might target the drivers of emissions as well in parallel, and as such create interaction. An example is a policy that affect the residual load such as the support for renewables, or a policy targeting the power system composition, such as decisions on a nuclear phase out, or specific requirements on fossil-fired generation such as the European large combustion plant (LCP) directive

(European Commission, 2001). Clearly, it is crucial to take into account these effects when designing policies. Finally, the shape of a derived MACC might impact the choice for either a price or a quantity based instrument.

The methodology also allows breaking up the MACC in its driving abatement technologies. Figures 4 and 5 indicate that up to a CO_2 emission cost of 35 EUR/tCO_2, all CO_2 abatement is caused by fuel switching. At higher CO_2 emission costs, both fuel switching and wind energy investments cause CO_2 emission abatement. The relative contribution of the different abatement technologies can be approximated based on the absolute emission plane. However, the relative contribution of the different abatement technologies can only be approximated as different abatement technologies interact with each other, meaning that the presence of one abatement technology can change the impact of the other abatement technology. Therefore, it is not possible to fully allocate abatement to one specific abatement technology. Figure 9 shows the contribution of fuel switching and wind energy investments in the marginal abatement cost curve of the power sector based on 2012 prices in case of no interaction between both abatement technologies (based on the imaginary case where only one abatement technology is present), and the total abatement if both abatement technologies are in place. The abatement caused by fuel switching as the only abatement technology follows from projecting Figure 4 on the absolute emission plane (see dotted line parallel to the marginal generation cost axis on figure 7a). Analogously, the abatement caused by wind energy investments as the only abatement option follows from projecting Figure 5 on the absolute emission plane (see dotted line parallel to residual load axis on figure 7a). It turns out that at higher CO_2 costs, negative interaction occurs, meaning that the total abatement caused by fuel switching and wind together is lower than the sum of the abatement if the abatement technologies are separately in place. Put differently, the presence of fuel switching reduces the impact of wind energy investment on CO_2 emission, and vice versa. This is however not a general conclusion, but determined by the values for the CO_2 emission drivers as used in this study (generation costs, residual load, power plant portfolio). Another setting of the CO_2 emissions drivers might lead to positive interaction (Weigt et al., 2013). With positive policy interaction, the impact of one policy instrument is enlarged by the presence of another policy instrument.

Several abatement options cause CO_2 abatement in a different but partially overlapping range of CO_2 costs, and interact with each other. Although it is difficult to precisely quantify ex-ante the CO_2 cost range in which a particular CO_2 abatement option will be active and what the interaction will be with other abatement options, policy makers should be aware of interaction effects between different CO_2 abatement options.

5. Conclusions and policy implications

This paper presents a methodology that deepens the insight in the relation between a CO_2 cost and CO_2 emission reductions in the power sector. The methodology is based on the insight that CO_2 emissions in the power sector are driven by the composition of the conventional power portfolio, the residual load (i.e., electricity demand minus renewables generation) and the generation costs of the conventional units. According to the presented methodology, a marginal abatement cost curve (MACC) of the power sector can be composed in three steps. First, the relation between a CO_2 cost and each of the CO_2 emission drivers has to be determined. Second, the relation between the CO_2 emission drivers and the CO_2 emissions in the power sector has to be determined. Third, the previous steps can be combined to determine the relationship between a CO_2 cost and CO_2 emissions in the power sector.

The main goal of the methodology is to give additional insight in the CO_2 cost-emission relationship, rather than deriving marginal abatement cost curves (MACCs). MACCs are facing the issue of robustness (i.e., sensitive to changes in external parameters) and granularity (i.e., not revealing the driving abatement technology at a certain CO_2 price). The presented methodology addresses both issues by showing the effect of changing external parameters and identifying the driving abatement technologies behind the aggregated MACC. The methodology also quantifies the interaction between different CO_2 abatement options. All this makes the methodology appropriate for policy makers, who can use the methodology to gain understanding of the impact of a CO_2 cost on the power sector and evaluate the robustness of this impact.

The usefulness of the methodology has been demonstrated by means of a case study of the 2012 Central Western European (CWE) power sector. Fuel switching and investments in wind energy are considered as possible abatement technologies in the power sector.

Based on the methodology and the case study discussed in this paper, three important policy implications can be formulated. First, policy makers should design their CO_2 emission policy in accordance with the robustness of the CO_2 abatement caused by an emission cost. The developed methodology provides insight (both qualitative and quantitative) in the CO_2 emission drivers in the power sector, and in how these can be influenced by a CO_2 price. Clearly, these drivers are also influenced by external factors or other policies. As such, a MACC (abatement potential at certain cost) is dependent on boundary conditions and should always be positioned as such. This can also impact the choice or preference between either a price or a quantity based instrument directly targeting CO_2.

Second, CO_2 abatement options are gradually deployed in a range of CO_2 costs. The case study shows that in the CWE power sector, investments in wind energy are only triggered as of a CO_2 cost of about 35 EUR/tCO_2. At lower CO_2 costs, only fuel switching occurs. However, fuel switching is still occurring at CO_2 costs above 35 EUR/tCO_2.

Third, policy makers should pay attention to interaction effects. The 2012 CWE example indicates negative interaction between fuel switching and wind energy investments. Negative interaction occurs when the impact of two CO_2 abatement options - which are simultaneously in place, triggered by a CO_2 price - is smaller than the sum of the abatement when they are in place as the only abatement option. Interaction between different CO_2 abatement options in the power sector is caused by the non-linear nature of the generation scheduling problem. This non-linear nature is captured by the so-called absolute emission plane, introduced in this paper. The negative interaction between fuel switching and wind energy, as indicated in this paper, is not a general conclusion as it depends on the considered case study and boundary conditions (e.g., fuel prices). It however shows the complexity of solid policy design.

Interactions between different energy and climate policies might occur, impacting the overall policy effect on CO_2 emissions.

Acknowledgements

The authors are grateful for the valuable comments and remarks of two anonymous reviewers. E. Delarue is a research fellow of the Research Foundation – Flanders (FWO).

References

Arroyo, J.M. and A.J. Conejo (2000). "Optimal response of a thermal unit to an electricity spot market." IEEE Transactions on Power Systems 15(3):1098-1104.

Carrión, M., and José M. Arroyo (2006). "A computationally efficient mixed-integer linear formulation for the thermal unit commitment problem." IEEE Transactions on Power Systems 21(3):1371-1378.

Criqui, P., S. Mima and L. Viguier (1999). "Marginal abatement costs of CO_2 emission reductions, geographical flexibility and concrete ceilings: an assessment using the POLES Model." Energy Policy 27(10):585-601.

Delarue, E., D. Ellerman and W. D'haeseleer (2010). "Robust MACCs? The topography of abatement by fuel switching in the European power sector." Energy 35(3):1465-1475.

EEA (2009). "Europe's onshore and offshore wind energy potential." Technical report No 6/2009.

EEX (2013). European Energy Exchange. Available at: www.eex.com.

Elia (2014). Belgian Transmission System Operator. Available at: www.elia.be.

Ellerman, D. and A. Decaux (1998). "Analysis of post-Kyoto CO_2 emissions trading using marginal abatement curves." MIT Joint Program on the Science and Policy of Global Change, Report No 40.

Entso-e (2014). European Network of Transmission System Operators for Electricity. Available at: www.entsoe.eu.

Eurelectric (2011). "Power Statistics and Trends 2011 – Full Report."

European Commission (2001) “Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.”

European Commission (2010). “Joint Research Centre – Prospective outlook on long term energy systems – POLES manual – version 6.1.”

Eurostat (2014). “Greenhouse gas emissions by sector.” Available at epp.eurostat.ec.europa.eu.

Fischer, C., and R. Morgenstern (2006). “Carbon abatement costs: why the wide range of estimates?” The Energy Journal 27(2):73-86.

IEA (2010). “Projected costs of generating electricity – 2010 Edition”. OECD Publishing, Paris.

Jacoby, H. (1998). “The uses and misuses of technology development as a component of climate policy.” MIT Joint Program on the Science and Policy of Global Change, Report No 43.

Kagiannas, A.G., D.A. Askounis, and J. Psarras (2004). “Power generation planning: a survey from monopoly to competition.” International Journal of Electrical Power & Energy Systems 26(6):413-421.

Kesicki, F., and P. Ekins (2012). “Marginal abatement cost curves: a call for caution.” Climate Policy 12(2):219-236.

Kesicki, F. (2013). “What are the key drivers of MAC curves? A partial-equilibrium modelling approach for the UK.” Energy Policy 58:142-151.

Klepper, G., S. Peterson and K. Springer (2003). “DART97: a Description of the multi-regional, multi-sectoral trade model for the analysis of climate policies.” Kiel Working Paper 1149, Kiel Institute of World Economics.

Klepper, G. and S. Peterson (2006). “Marginal abatement cost curves in general equilibrium: the Influence of world energy prices.” Resource and Energy Economics 28(1):1-23.

Labandeira, X., P. Linares and M. Rodriguez (2009). “An integrated approach to simulate the impacts of carbon emissions trading schemes” The Energy Journal 30(2):217-239.

Morris, J., S. Paltsev and J. Reilly (2012). “Marginal abatement costs and marginal welfare costs for greenhouse gas emissions reductions: results from the EPPA Model.” Environmental Modeling & Assessment 17(4):325-336.

Paltsev, S., J. Reilly, H. Jacoby, R. Eckaus, J. McFarland, M. Sarofim, M. Asadoorian and M. Babiker. (2005). “The MIT emissions prediction and policy analysis (EPPA) Model: version 4.” MIT Joint Program on the Science and Policy of Global Change, Report No 125.

Rootzén, J., and F. Johnsson (2013). “Exploring the limits for CO_2 emission abatement in the EU power and industry sectors—Awaiting a breakthrough.” Energy Policy 59: 443-458.

Tennet (2014). Dutch Transmission System Operator. Available at: www.tennet.org.

Umweltbundesamt (2014). German Environmental Protection Agency. Available at: www.umweltbundesamt.de/energie/archiv/kid.php.

Van den Bergh, K., E. Delarue and W. D'haeseleer (2013). “Impact of renewables deployment on the CO_2 price and the CO_2 emissions in the European electricity sector.” Energy Policy 63:1021-1031.

Van den Bergh, K., K. Bruninx, E. Delarue and W. D'haeseleer (2014). “A mixed-integer linear formulation of the unit commitment problem.” Working paper KU Leuven, available at: www.mech.kuleuven.be/en/tme/research/energy_environment/PublicationsEnergyandenvironment.

Vogt-Schilb, A. and S. Hallegatte (2014). “Marginal abatement cost curves and the optimal timing of mitigation measures.” Energy Policy 66: 645-653.

Weigt, H., Ellerman, D., Delarue, E. (2013). “CO_2 abatement from renewables in the German electricity sector: does a CO_2 price help?” Energy Economics 40:149-158.

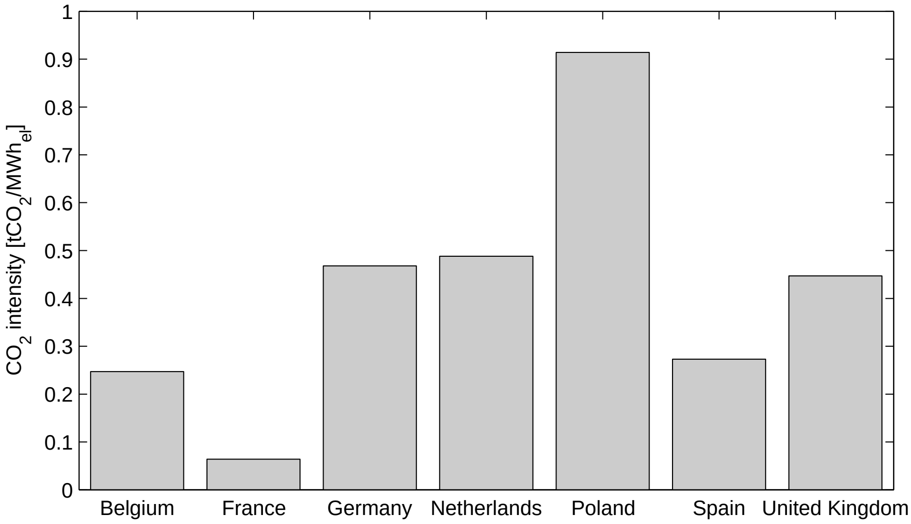


Figure 1. The CO_2 intensity of electricity generation varies strongly from country to country, depending to a large extent on the installed generation portfolio - 2009 data (Eurelectric, 2011).

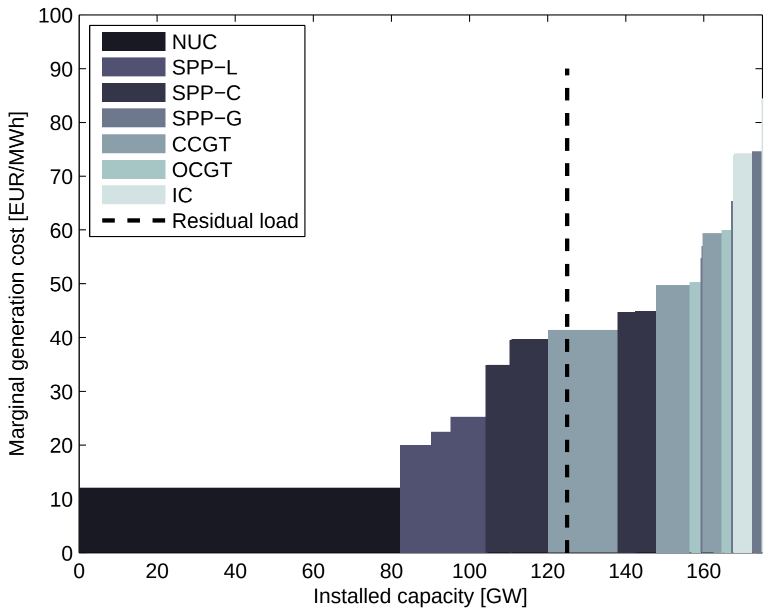


Figure 2. Merit order of the CWE region (based on 2012 data) and the inelastic average residual load. NUC: nuclear units, SPP-L: lignite fired steam power plants, SPP-C: coal fired steam power plants, SPP-G: gas fired steam power plants, CCGT: combined cycle gas turbines, OCGT: open cycle gas turbines, IC: internal combustion engines.

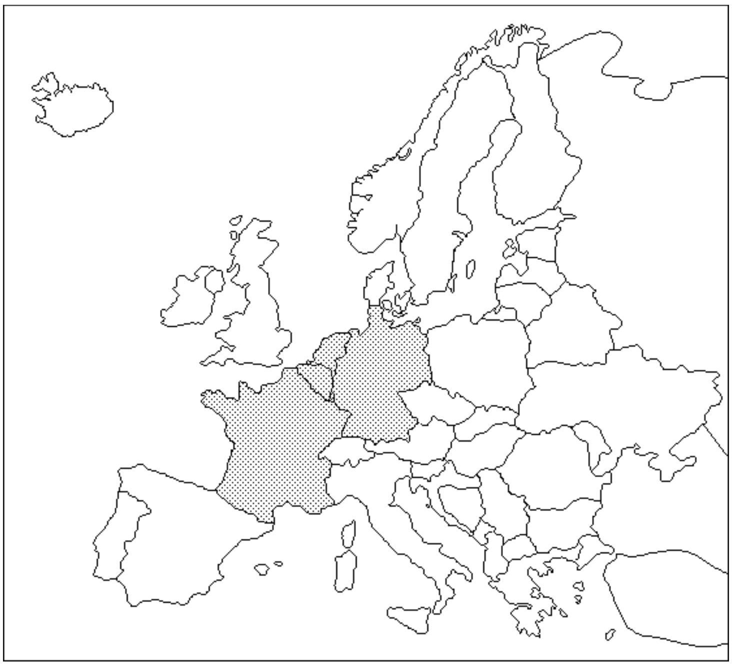


Figure 3. Map of Europe with the CWE region denoted in gray.

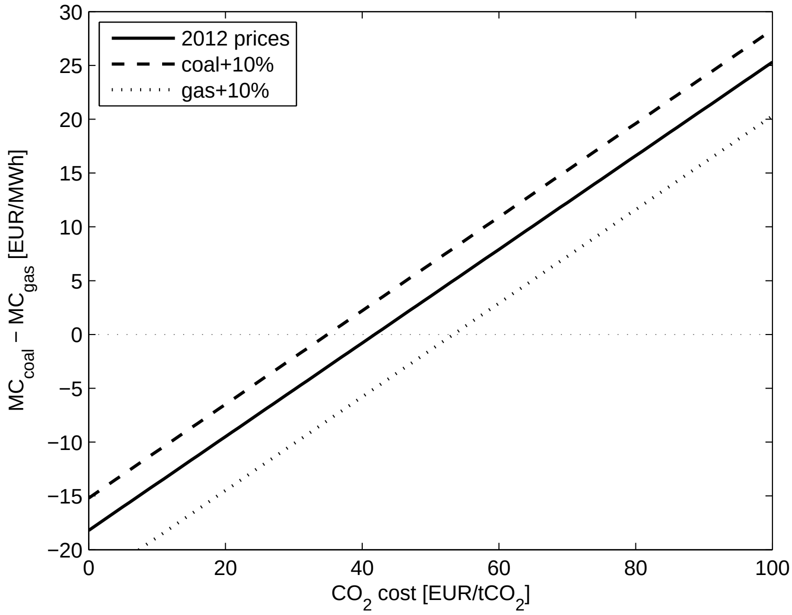


Figure 4. Relation between a CO_2 cost and the difference in average marginal generation cost between coal and gas fired power plants, used as a metric for the marginal generation costs of the conventional power plant portfolio.

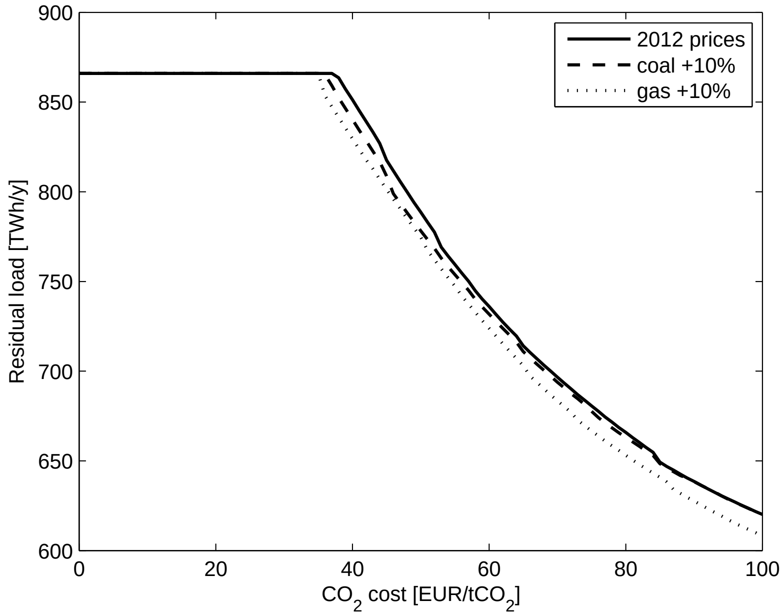


Figure 5. Relation between a CO_2 cost and the residual load, caused by investments in new wind capacity.

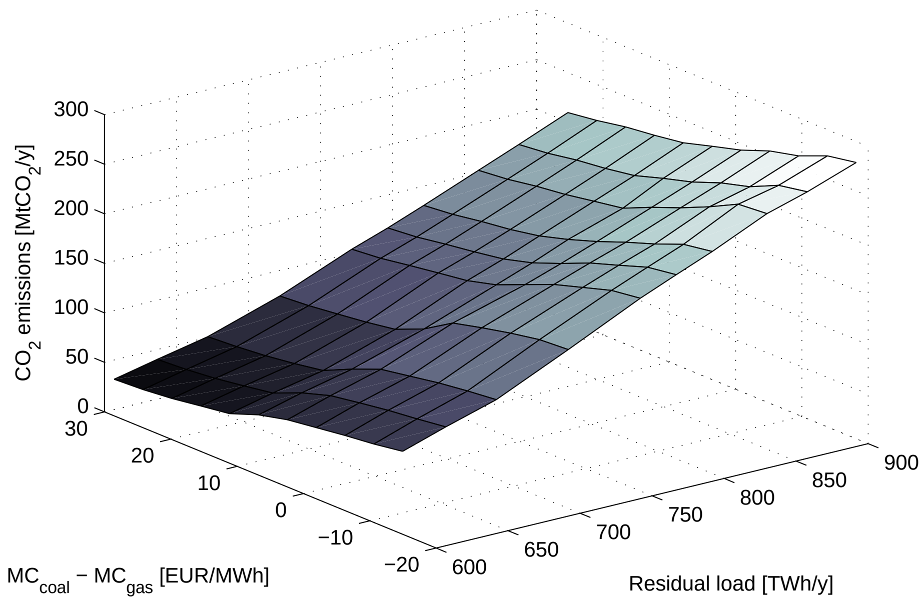
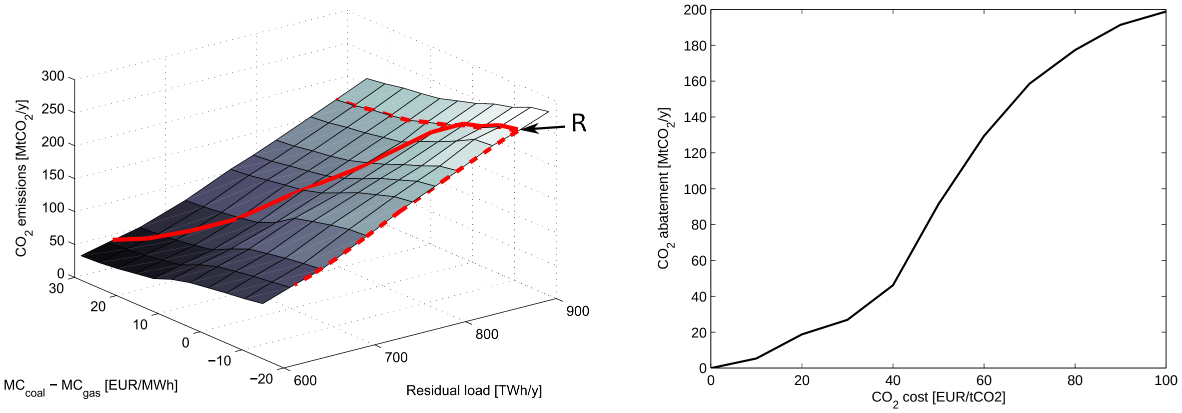
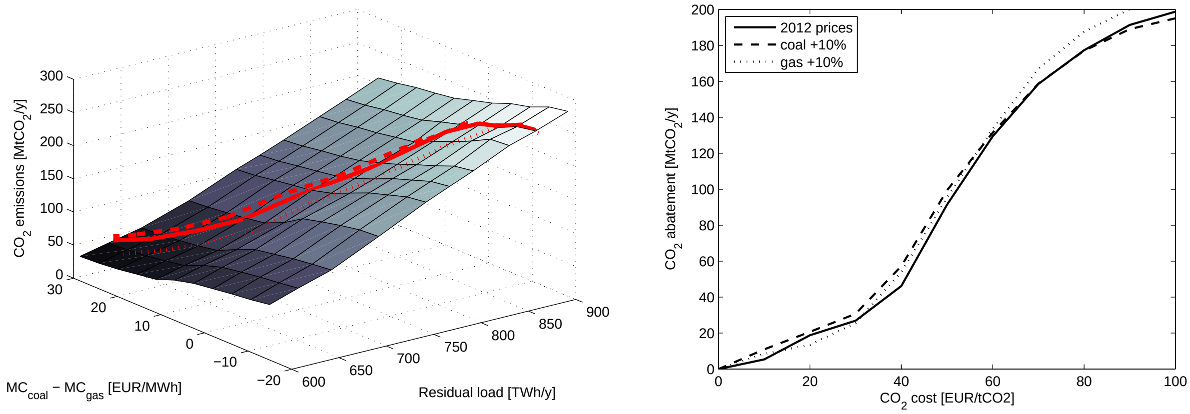


Figure 6. The absolute emission plane of the CWE power sector, based on 2012 data.



a) Absolute emission plane. b) Marginal abatement cost curve.

Figure 7. The marginal abatement cost curve can be derived by projecting the CO_2 cost-driver relations on the absolute emission plane. Figures 4 and 5 link the left panel with the right panel.



a) Absolute emission plane. b) Marginal abatement cost curve.

Figure 8. The marginal abatement cost curve depends on the fossil fuel prices imposed to the power system.

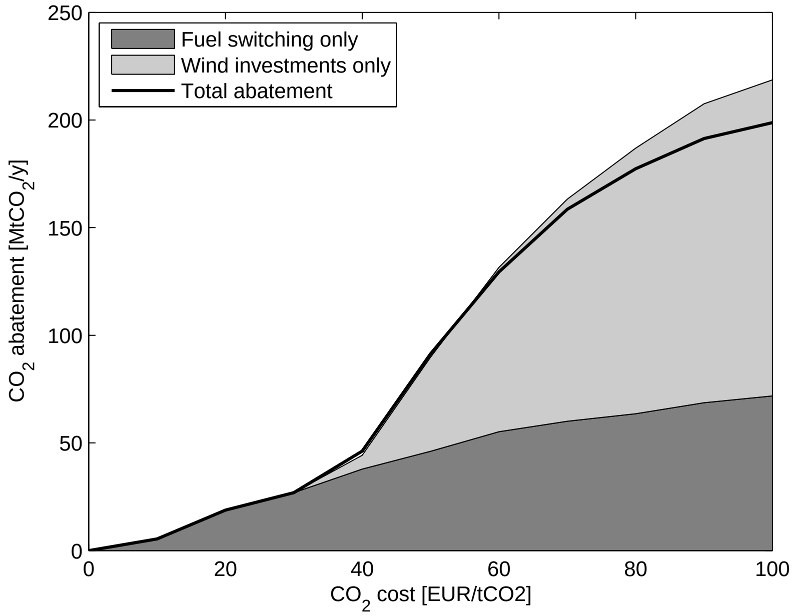


Figure 9. Relative contribution of fuel switching and wind energy investments to CO_2 abatement.

Table I. Overview of the 3 main CO_2 emission drivers in the power sector.

CO_2 emission driver	Possible abatement options	Time frame
conventional portfolio	• investments in nuclear power plants • investments in gas fired plants • closing down lignite or coal fired plants • retrofitting fossil fuel fired plants • carbon capture and storage	long term (several years)
residual load	• investments in renewable generation capacity • increasing the efficiency of appliances • demand reduction due to higher electricity prices	medium term (months-years)
marginal generation costs	• fuel switching	short term (days-months)

Table II. Overview of installed capacity in the 2012 Central Western European region. Different rated efficiencies are allocated depending on the year of commissioning. The highest rated efficiency is allocated to units commissioned or retrofitted after 2000, the middlemost to units commissioned between 1980 and 2000, and the lowest to units commissioned before 1980.

	Capacity [GW]	Efficiency [%]	Min. output [$\%P_{max}$]	Up/down time [h]
NUC	82	33	50	168
SPP-C	26	35/40/46	43	6
SPP-L	22	35/40/46	43	24
SPP-G	4	35/40/46	32	5
CCGT	31	40/48/58	35	3
OCGT	5	35/42	30	1
IC	5	35/40/48	35	3

Table III. Nomenclature used in the model description.

Sets		**Parameters**	
I (i)	Set of power plants	$A_{l,n}$	Grid incidence matrix {-1,0,1}
L (l)	Set of transmission lines	$AP_{n,i}$	Matrix linking plant i to node n {0,1}
N (n)	Set of nodes	CO_i	Generation cost at min. output [EUR/h]
T (t)	Set of time steps	$D_{n,t}$	Electricity demand in [MW]
Variables		F_l^{max}	Capacity limit in [MW]
$i_{n,t}$	Grid injections in [MW]	MC_i	Marginal generation cost in [EUR/MWh]
$f_{l,t,}$	Line flow in [MW]	MDT_i	Minimum down time in [h]
$p_{i,t}$	Output above min output in [MW]	MUT_i	Minimum up time in [h]
$u_{n,t}^{RES}$	Renewables curtailment in [MW]	P_i^{max}	Maximum power output in [MW]
$v_{i,t}$	Start-up status {0,1}	P_i^{min}	Minimum power output in [MW]
$w_{i,t}$	Shut-down status {0,1}	SUC_i	Start-up cost in [EUR/start]
$z_{i,t}$	On/off-status {0,1}	$T_{n,t}^{CHP}$	Generation from cogeneration in [MW]
		$T_{n,t}^{RES}$	Generation from renewables in [MW]

Table IV. Overview of the levelized cost of electricity (LCOE) and the technical potential of wind energy in the CWE region (IEA, 2010; EEA, 2009).

	LCOE [EUR/MWh]		Technical potential [GW]	
	Wind onshore	Wind offshore	Wind onshore	Wind offshore
Belgium	68	128	250	11
The Netherlands	58	88	350	110
Germany	71	94	2000	80
France	61	98	2700	90